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A Design Tool for the Optimization of Stand-alone Electric Power Systems with Combined Hydrogen-Battery Energy Storage

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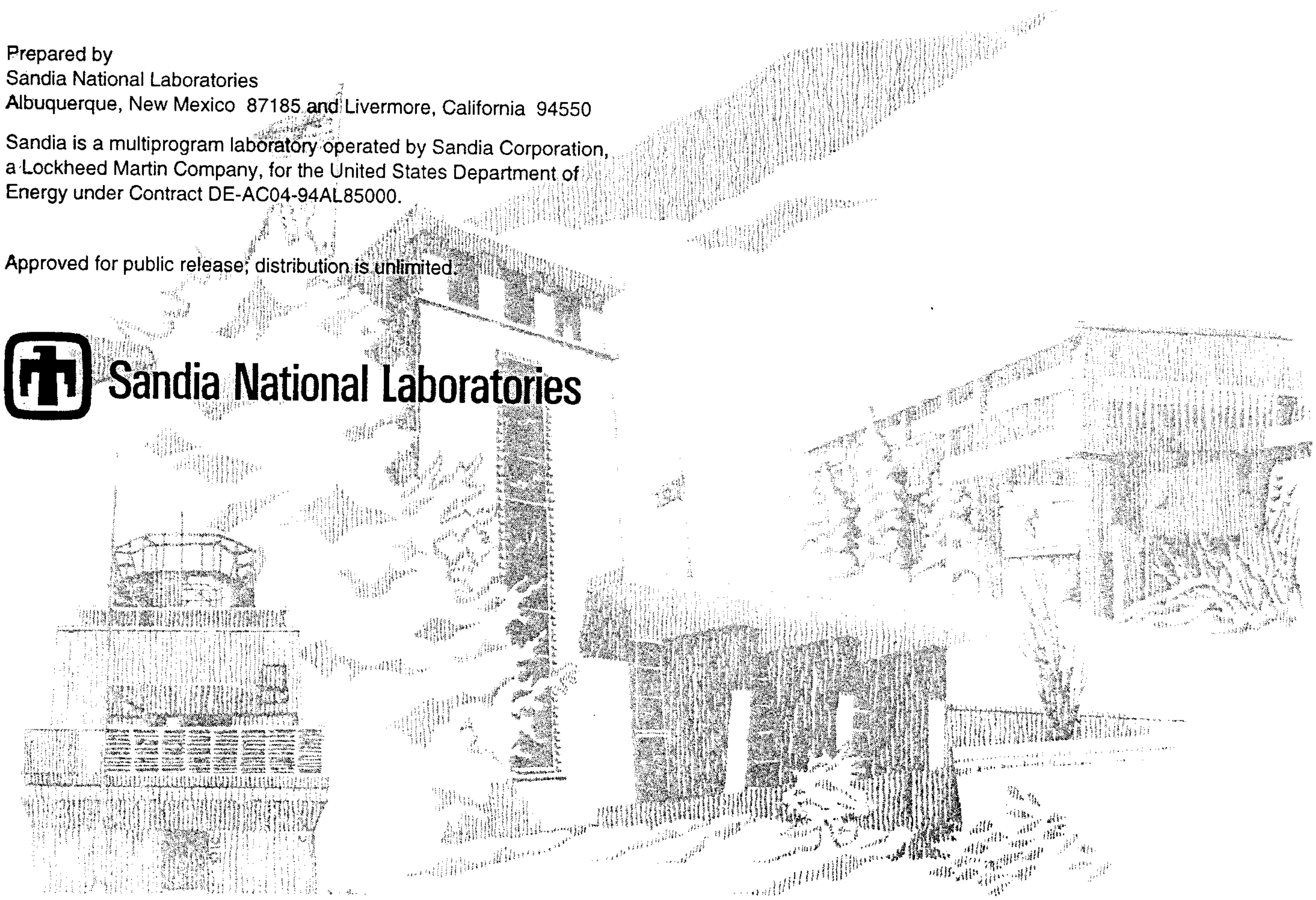

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A Design Tool for the Optimization of Stand-alone Electric Power Systems with Combined Hydrogen-Battery Energy Storage

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ABSTRACT

A simulation design tool was developed to investigate the design and performance of stand-alone distributed renewable electric power systems. The temporal mismatch between energy production and use results in the inclusion of energy storage devices that can become an important and expensive component of these systems. To properly size all system components, a time response model with one hour resolution was developed. Specifically, the model developed here simulates one year of grid operation with the constraint that it be "stand-alone" - that is, that there be no net change in stored energy. With two storage components, hydrogen and batteries, the system size was calculated as a function of the battery storage size, and the total system was costed with battery size as the parameter. Calculations were performed for the specific case of residential use in Yuma, Arizona. In addition to determining the size and cost of this grid, it was found that the system costs using a combination of hydrogen and battery storage was less expensive than either one individually.

Table of Contents

ILLUSTRATIONS

TABLES

BACKGROUND

Interest in stand-alone electric microgrids is increasing as more remote areas of the world become industrialized. In addition, there is an interest in incorporating renewable energy sources into these systems. The purpose of this report is to describe a model of stand-alone (distributed or off-grid) electric power systems. The model was applied to the design of photovoltaic (PV) electric systems with hydrogen and/or battery energy storage. The specific design is dependent on geographically dependent parameters such as solar flux and heating or cooling requirements. In this report calculations are presented for homes located in Yuma, AZ. The philosophy of this effort is to produce electric power systems that are functionally the same as one that is grid-connected. Since electric usage does not follow the variation of solar flux throughout the day, some PV generated electricity must be stored for use during other times of the day. The approach taken here was to develop a model detailed enough to size individual components based on their maximum usage throughout the year. Some components are costed based on total storage (kWh), while others depend on the rate of use (kW). This warrants developing a model that tracks the storage requirements on an hour-by-hour basis throughout the year. The overall system design will provide the customer with their power needs throughout the year, thus providing a truly stand-alone power system.

MODEL

A time response system model was developed for the design of solar-hydrogen electric microgrid (see Figure 1). The system was assumed to consist of one home[*] with a photovoltaic (PV) array, a time varying load, a hydrogen storage subsystem (electrolyzer-hydride tank-fuel cell combination) and a bank of batteries. Power exchange between components was in the form of alternating current to allow for siting flexability. Energy in excess of that needed to power the load was stored first in the batteries, with any excess being stored as hydrogen. This is not necessarily the most efficient storage algorithm, but for the cases studied here, it has the desired effect of using the relatively efficient batteries to take care of daily load peaks, while using the hydrogen stored in a hydride bed (with its smaller cost per kWh stored, see Appendix C) for longer term storage. For a given solar flux and usage load, the model outputs are the sizes of the PV array, electrolyzer, hydrogen storage and fuel cell as a function of the amount of battery storage.

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[*] After optimizing the system components on a per house basis, scaling up to clusters of homes could be done by considering the actual size of commercially available fuel cells and electrolyzers.

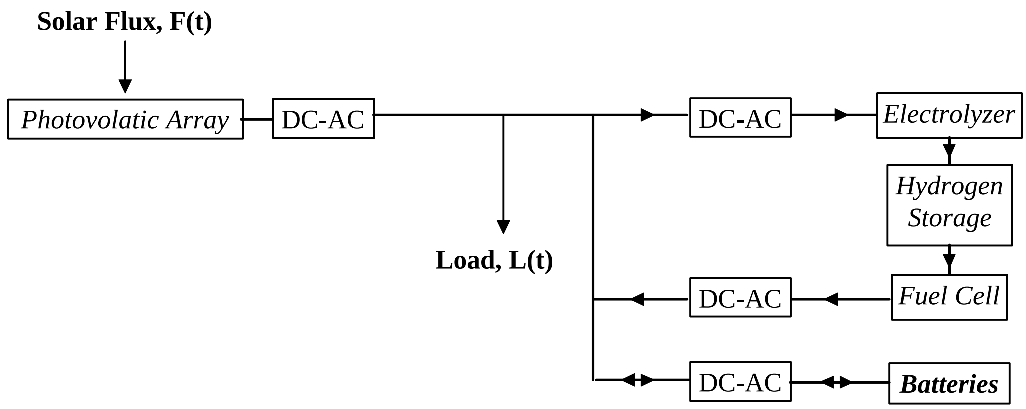

Figure 1. Schematic of the Solar-Hydrogen-Battery electric grid system. Model inputs are shown in bold type, parameters are shown in bold italic, and output parameters are shown in italics.

Given a yearly variation in load and solar flux and a battery size, the PV array and hydrogen storage subcomponents were sized so that no additional energy is needed at any time throughout the year. Since there are four unknowns (array, fuel cell, electrolyzer and battery sizes) and two boundary conditions (no net change in the energy stored in either the hydrogen or batteries over one year), it is possible to obtain system designs with one parameter; battery storage capacity was chosen to be that parameter. After making estimates of component costs, the total initial system and annualized costs were determined.

The focus of this report is on the modeling effort, especially as it relates to optimizing the storage components. The need for storage is highlighted in Figure 2. Figure 2a shows the solar flux and assumed residential usage (described below) during the peak solar flux (June 21), and Figure 2b is for the minimum solar flux (December 21). The load and flux histories, derived in Appendix A and B respectively, follow similar trends with an early load peak just at or before sunrise, followed by reduced usage in the middle of the day and another peak near or just after sunset. To provide power for the load peaks in the morning and evening it is necessary to store energy during the peak noontime flux. In addition, the day-to-day variations in solar flux and load do not match one another. In the summer, the load/flux ratio is 4.16 and in the winter it is 4.53. Thus, on average, solar energy collected in the summer will be stored for use in other times of the year.

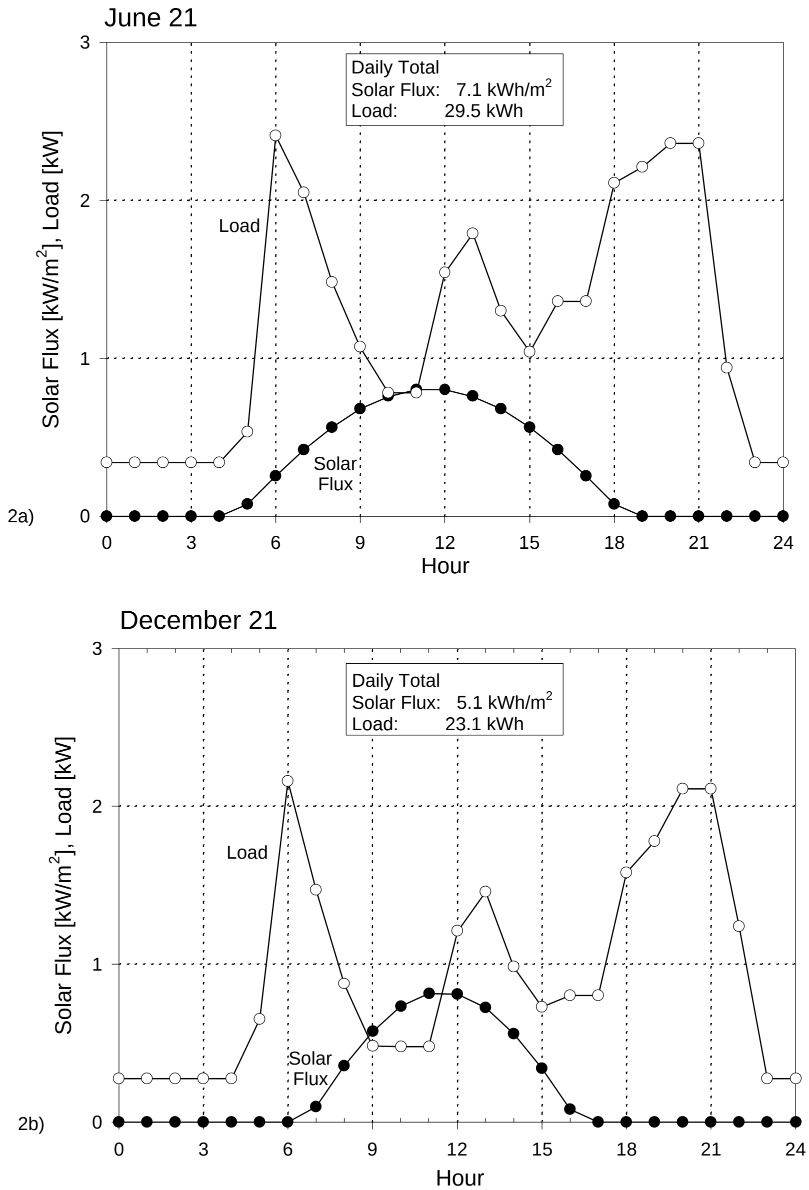

Figure 2. Solar flux and loads for days with the a) longest and b) shortest number of daylight hours.Figure 2. Solar flux and loads for days with the a) longest and b) shortest number of daylight hours.

Assumptions

Details on the solar flux and load calculations are described in Appendix A and B respectively, and the component efficiencies, costs and lifetimes are discussed in Appendix C. The main assumptions are noted in this section. The solar flux calculations were done using measured 30 year averages for a solar collector with a fixed elevation equal to the latitude. Hourly variations in flux were calculated using the change in sunrise and sunset as a function of day of year.

Load histories were constructed for air conditioning, appliance and lighting loads. It was assumed that space and water heating was either solar or utilized otherwise waste heat from the fuel cell. From annual or monthly loads, hourly loads were synthesized using assumed hourly use profiles. Electricity was converted to AC for transport between components and for residential for use on the microgrid. All cost and performance information was taken for current state-of-the-art commercial equipment.

Another important assumption in this model is the algorithm used to partition energy into and out of the two storage devices. The model assumes that short term energy storage favors batteries due their high storage efficiency. Energy in excess of the load is stored in batteries until fully charged, with further excess energy stored as hydrogen. To make up load not supplied by the PV, batteries are used until a minimum charge is reached, with the excess energy coming from the hydrogen. Consequences of this algorithm will be discussed below.

Simulation Method

System time response simulations were conducted on an hourly basis throughout one year. A spreadsheet was used to produce the load and solar flux histories following the discussion in Appendix A and B. A computer code was written to take these inputs, along with a given battery size, and calculate the hydrogen storage component sizes and PV array size, with the constraint that there be no net change in the amount of energy stored in either the hydrogen or battery systems at the end of the simulation period. This algorithm worked as follows:

1. The load and solar flux histories produced from a spreadsheet model were input to the program.
2. Battery storage size was input.
3. Initial guesses for the PV array size and hydrogen component sizes were made.
4. A one-year simulation was made using the following algorithm:
   a) On an hour-by-hour basis, the amount of energy to exchange through storage was calculated. This is the amount of PV generated electricity minus the load.
   b) For each hour, if the batteries could handle the storage requirement, energy was taken from or put into the batteries.
   c) Any excess requirement was fulfilled by the electrolyzer (for energy storage) or the fuel cell (for energy storage withdrawal).
5. At the end of a one year simulation the following was done:
   a) If the year-to-year change in hydrogen storage was less than a convergence criteria (typically one part in 10,000 of the maximum hydrogen storage), a solution had been obtained.

b) The PV array size was adjusted to minimize the year-to-year change in hydrogen storage. If there was excess hydrogen, the PV array size was decreased, and if there was a deficiency in hydrogen, the PV array was increased.
c) The year end battery storage charge was transferred to the beginning of the next simulation year.

6. Steps 4 and 5 were repeated to convergence.
7. The resulting component sizes were used to produce a system cost estimate.

SIMULATION RESULTS

Using the total load and solar flux, simulations of the system performance were carried out for one year in hourly increments. Since this system is meant to be "stand-alone", components were sized so that there was always electricity when needed (either from the PV, batteries or hydrogen), and that at the end of the year that there was no net change in the energy strored in the batteries or hydrogen. This was done by varying the value of stored energy and the PV array size at the beginning of the simulation until energy conservation was satisfied. For the storage algorithm used, solutions (that is the component sizes) are expressed parametrically in terms of the battery capacity. The total energy storage capacity is presented in Figure 3. In the limit of no battery storage, 789 kWh equivalent of hydrogen storage is needed[**]. With battery storage only, 883 kWh of storage is needed. Since batteries are more energy efficient that hydrogen energy storage systems, battery systems require a smaller PV array than hydrogen energy storage systems (Figure 4). The smaller array size is due in part to the efficiency advantage of batteries over the hydrogen storage system.

Hybrid systems exhibit an interesting effect, with a minimum in storage capacity (as well as in cost, as to be shown later). A small amount of battery storage increases the overall system efficiency, thus dropping the total capacity requirement. This is due mainly to the large difference in energy storage efficiency, which results in a small amount of battery storage replacing a large amount of hydrogen storage capacity. As more battery storage is added to the system, there is a minimum in the total storage capacity at roughly one days equivalent of battery storage. In effect, the batteries are being used for daily storage and the hydrogen is being used for longer term storage.

[**] Since the heat of reaction of hydrogen is 285,000 joule/mole hydrogen , and the standard concentration of hydrogen is 40.6 mole/m^3, the energy content of hydrogen is 3.22 kWh/Nm^3. Thus the 789 kWh of hydrogen storage is accomplished with ~ 245 Nm^3.

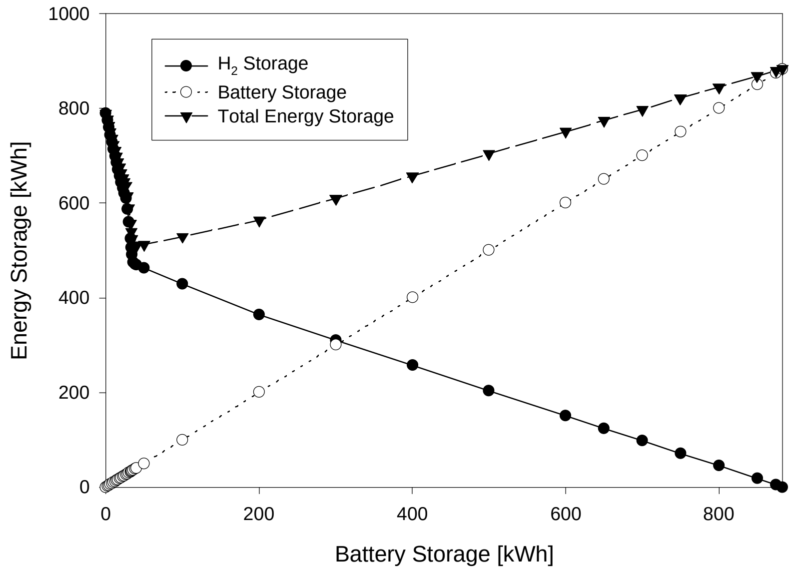

Figure 3. Energy storage requirements as a function of battery storage size. A small amount of battery storage increases the overall system efficiency and decreases the total storage requirements.

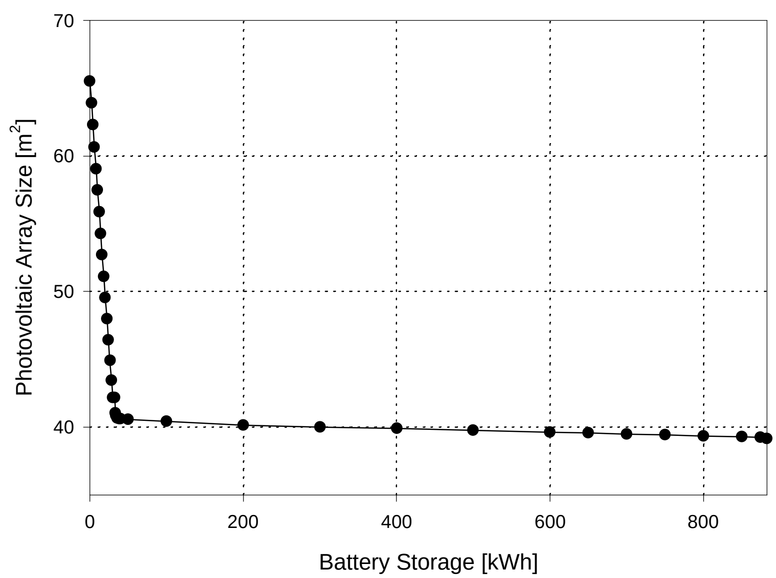

Figure 4. Variation in photovoltaic array size requirement with battery storage size.

The effect of increasing the battery storage size on other system components is shown in Figure 5. In that figure, the size of the PV array, hydrogen storage, fuel cell and electrolyzer (normalized to the hydrogen only case) are shown as a function of battery storage size. There is a rapid decrease in component size for small increases in battery storage, up to about 30 kWh. The fuel cell and electrolyzer are both sized based on peak power throughput. Batteries can satisfy the peak demands, thus having a dramatic effect on the fuel cell and electrolyzer size (a 35% and 60% reduction, respectively for 30 kWh of batteries). Since batteries are more efficient energy storage devices than the hydrogen system, there is also a 40% reduction in the PV array size. As the battery size is increased above the 30 kWh level (about one days use), the effect of increased battery storage is minimal until batteries become the dominant storage mechanism.

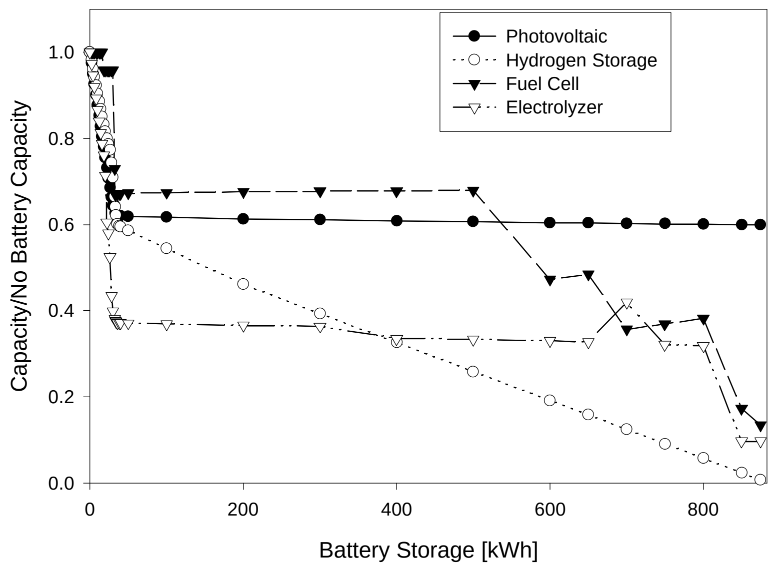

Figure 5. Normalized photovoltaic array size and hydrogen storage requirements as a function of battery storage size.

The cost of this system is shown in Figure 6. The "Initial Cost" is the total value of all the components normalized by the cost of a no battery system. The "Annualized Cost" is the normalized annual cost of the system at 0% interest, assuming component lifetimes listed in Appendix C. The battery only system is many times more expensive than the no battery system - the Initial Cost is ~ 3 times and the Annualized Cost is ~ 7 times the cost of the hydrogen only system. Although the battery only system has a smaller PV array,

Figure 7 shows the detail of Figure 6 near the limit of small battery storage size. Both costs are a minimum for 33 kWh of battery storage. The Initial Cost is reduced by 30%, and the Annualized Cost is reduced by 20% over the no battery system. This large improvement in the cost results from matching the energy storage devices for specific duties - batteries handle short term storage and hydrogen long term storage. and thus must have a higher energy use efficiency, the cost savings are offset by the cost of batteries.

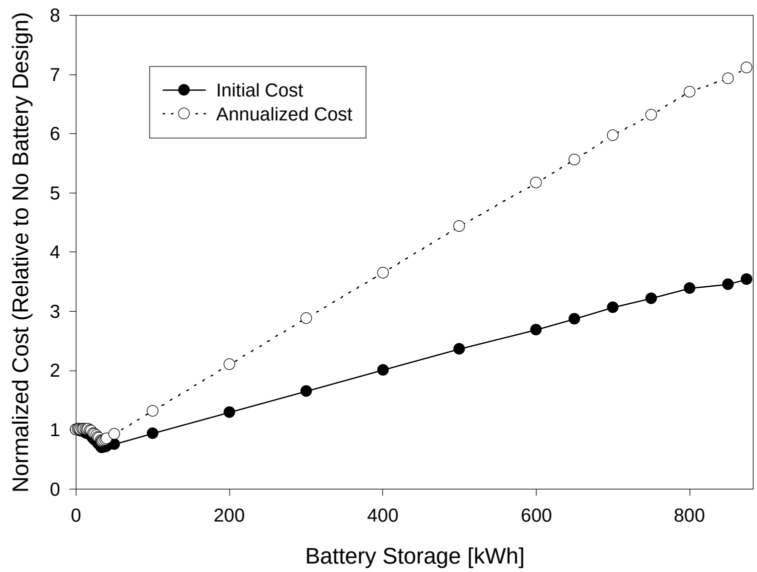

Figure 6. Normalized initial and annualized system costs as a function of battery storage size.

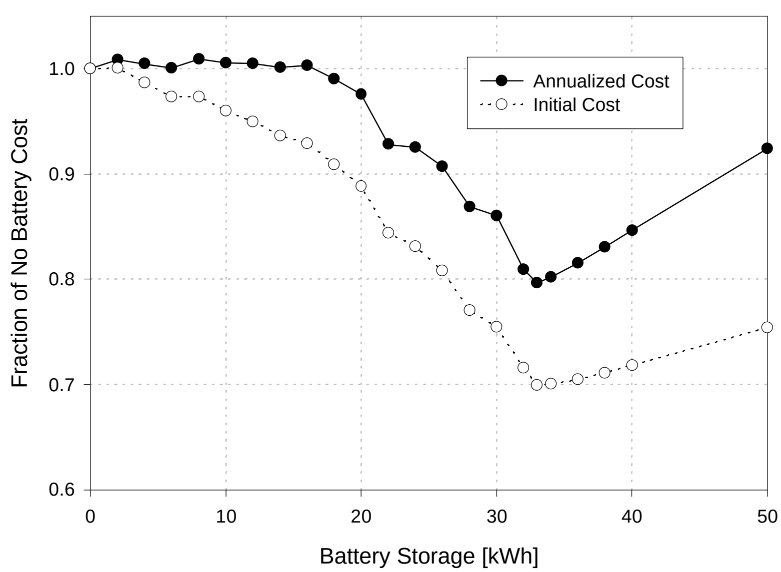

Figure 7. Normalized initial and annualized system costs as a function of battery storage size. This figure shows detail from Figure 6 arround the minimum cost configuration.

Minimum Cost Design

A practical system will probably be close to the minimum cost solution, which is 33 kWh of battery storage and 450 kWh of hydrogen storage. The hourly storage variations over one day are shown in Figure 8 for the summer (June 21) and winter (December 21). In Figures 8 and 9 the storage usage is normalized for each of the components (a value of 1.0 represents 33 kWh of battery storage and 450 kWh of hydrogen storage). The hydrogen storage is nearly flat, with slight variations necessary to accomplish long term input energy-load matching. In the summer the hydrogen storage is nearly full, and in the winter it is nearly empty. The battery storage nearly follows the hourly load-solar flux mismatch, decreasing to a minimum near sunrise, and increasing to a maximum near sunset. Long term use is shown in Figure 9, where storage usage is shown early in the morning and late in the afternoon. The daily variation in hydrogen storage is small, and the two hydrogen curves are nearly identical. The hydrogen storage is a minimum on March 1, and a maximum on July 1. The secondary peak in early November is the result in a decrease in cooling load in October. The batteries are nearly always charged at 5 pm and are at their minimum charge at 7 am.

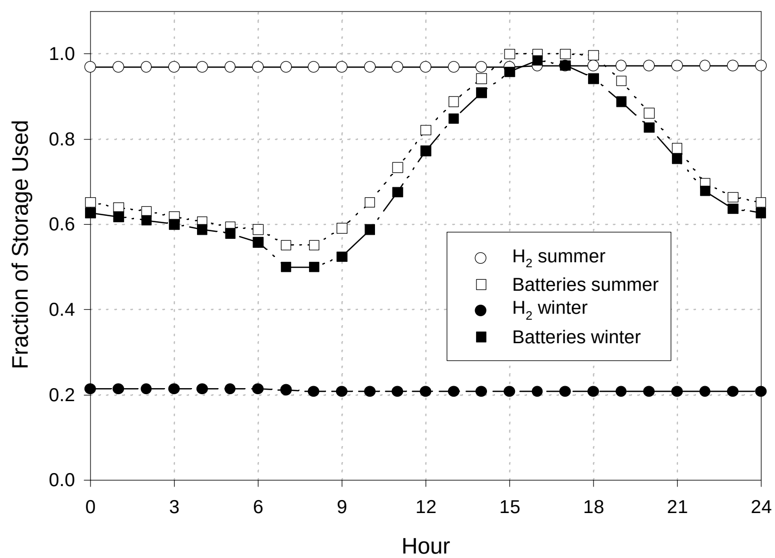

Figure 8. Variation of hydrogen and battery electrical storage with time for the summer and winter.

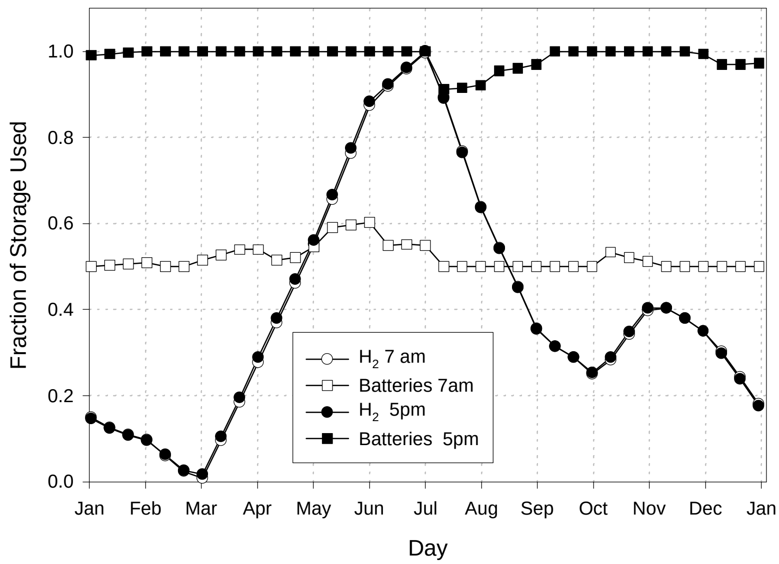

Figure 9. Variation in hydrogen and battery storage in the morning and evening, throughout the year.

CONCLUSIONS

A powerful system design capability has been developed to perform system analysis on distributed renewable power systems. System components may include several different energy storage and power generation devices. This system capability, in the form of a numerical model, is readily adaptable to different renewable energy supply characteristics, storage technologies and end use profiles. This capability was used to design a photovoltaic/hydrogen/battery distributed power system suitable for an application in the very hot and sunny environment of Yuma, Arizona. It was shown optimal cost designs exist when combining highly efficient, expensive energy storage devices (batteries) for short-term storage with less efficient components that can store large amounts of energy less expensively (hydrogen) for long-term storage.

APPENDIX A - LOAD

To accurately model the system response it is important to have information on the hourly variation of the load. Because this information was not available to us, hourly usage profiles were simulated using published annual or monthly census data. Information on heating and cooling requirements were available both as annual averages and monthly averages. Information on appliance usage, including lighting, was available on an annual basis.

Solar Flux and Heating/Cooling Requirements

The heating and cooling requirements were estimated from climatalogical data of Yuma, Arizona. The average daily cooling requirement varies month-to-month as in Table I. Heating Degree Days (HDD) and Cooling Degree Days (CDD) are a measure of how often the temperature varies from an acceptable temperature of 65 F. To convert from HDD and CDD to heating and cooling load it is necessary to account for construction materials and home size as well as the efficiency of heating and cooling system. National average values for cooling are 0.77 kWh/CDD * 1000 square feet and for heating are 0.94 kWh/CDD * 1000 square feet[1]. We assumed a 1000 square foot air conditioned home, with other (solar) means utilized for space and water heating. In addition, it was assumed that advanced insulation techniques could cut the cooling requirements in half. Thus, the space and water heating load was taken as 0 kWh, and the cooling requirements as 385*CDD.

Table I. Heading and cooling requirements for Yuma, Arizona calculated from degree day data [2] and cooling load for data for active cooling.[1] Space heating was assumed to come from other solar (passive) means.

Month	Degree Days (65 F)		Cooling Load	
	HDD	CDD	kWh	kWh/day
January	308	10	3.85	0.12
February	192	37	14.24	0.51
March	97	62	23.87	0.77
April	24	210	80.85	2.70
May	0	425	163.63	5.28
June	0	624	240.24	8.01
July	0	890	342.65	11.05
August	0	862	331.87	10.71
September	0	663	255.26	8.51
October	5	343	132.06	4.26
November	108	63	24.25	0.81
December	276	6	2.31	0.07
Total	1010	4195	1615.08	

Other Usage

Average total residential electric use is available for all areas of the country as a function of end-use. The data is divided by census region, urban status, climatic zone, type of housing, and home size. For this study, data for Yuma, AZ was used. The usage[3] is 1729 kWh/year for refrigeration, 6418 kWh/year for all other appliances. Because lighting use in particular does not follow the solar flux it was thought that a lighting estimate (which is included in "other appliances") would be important for our model. The national breakdown of appliance usage is given[4] in Table II. These values were modified month-by-month to reflect changes in the lighting load due to changes in the amount of natural light. The daily electric usage as a function of month is shown in Table III.

Table II National daily average appliance electric energy usage.

Use	Fraction of "All Appliance" Usage	kWh/year
Lighting	19%	1219
TV	15%	959
Clothes Dryer	10%	648
Freezers	8%	545
Ovens	6%	363
Other	42%	2684
Total "All Appliances"	100%	6418

Table III. Monthly variation in electric energy use, kWh/day.

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total (kWh/yr)
Heating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0
Cooling	0.12	0.51	0.77	2.70	5.28	8.01	11.05	10.71	8.51	4.26	0.81	0.07	1615
Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0
Lighting	4.37	4.84	4.37	4.51	2.18	2.26	2.18	2.18	2.26	2.18	4.51	4.37	1219
TV	2.58	2.86	2.58	2.67	2.58	2.67	2.58	2.58	2.67	2.58	2.67	2.58	959
Clothes Dryer	1.74	1.93	1.74	1.80	1.74	1.80	1.74	1.74	1.80	1.74	1.80	1.74	648
Freezers	1.46	1.62	1.46	1.51	1.46	1.51	1.46	1.46	1.51	1.46	1.51	1.46	545
Ovens	0.98	1.08	0.98	1.01	0.98	1.01	0.98	0.98	1.01	0.98	1.01	0.98	363
Other	7.22	7.99	7.22	7.46	7.22	7.46	7.22	7.22	7.46	7.22	7.46	7.22	2684
Refridge.	4.65	5.15	4.65	4.80	4.65	4.80	4.65	4.65	4.80	4.65	4.80	4.65	1729
Total	23.12	25.97	23.76	26.46	26.09	29.51	31.86	31.51	30.01	25.07	24.57	23.07	9762

Hourly Usages

The monthly valued of daily use were converted to hourly use through the assumed usage profile shown in Figure A-1. Likely usage profiles assumed that the morning and evening had the greatest use, with some noontime activity. Since the simulation was performed on an hourly basis, the fraction of total energy used per hour converted the kWh/day to kWh/hour of power use.

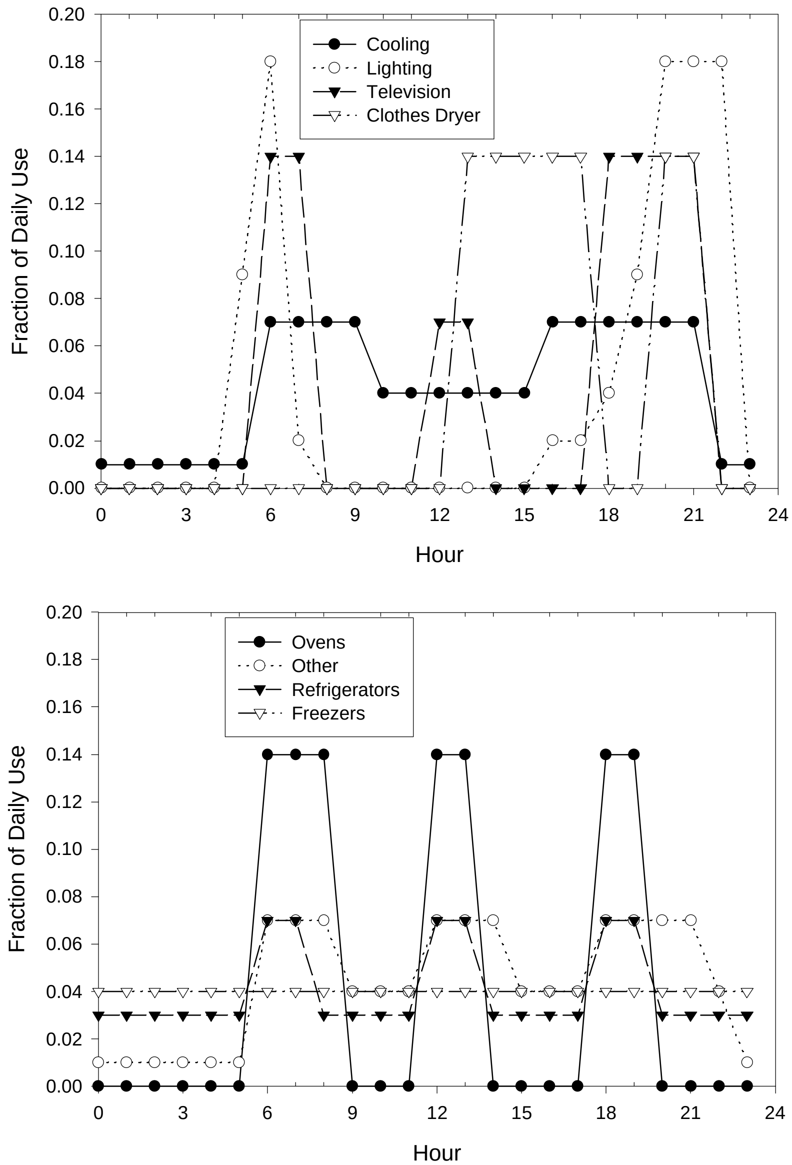

Figure A-1. Normalized hourly usage for all loads.

APPENDIX B - SOLAR FLUX

The collected solar flux depends on the location and orientation of the solar collectors. The greatest collection efficiency is obtained for collectors oriented south-facing, with an elevation equal to the latitude. Hourly estimates were obtained by using measured solar flux data for Tuscon, Arizona, the nearest recording location to Yuma, Arizona, (Table IV) along with sinusoidal varying flux curves synthesized from the total daily flux and sun rise and sun set times obtained from a generalized sky chart (Table V).

Table IV. Average solar flux for a collector at the latitude angle.[5]

Month	Solar Flux kWh/m^2-day Average - Latitude
January	5.4
February	6.2
March	6.7
April	7.3
May	7.3
June	7.1
July	6.4
August	6.6
September	6.8
October	6.6
November	5.8
December	5.1

Table V. Sun rising and setting times for Yuma, Arizona from a generalized sky chart.[6]

Date	sun rise (am)	sun set (pm)
20-Jan	6.80	5.00
20-Feb	6.50	5.50
22-Mar	6.00	6.00
21-Apr	5.50	6.50
22-May	5.25	6.75
21-Jun	5.00	7.00
22-Jul	5.25	6.75
21-Aug	5.50	6.50
21-Sep	6.00	6.00
21-Oct	6.50	5.50
20-Nov	6.80	5.20
21-Dec	7.20	4.80

APPENDIX C - COMPONENT EFFICIENCIES, COSTS AND LIFETIMES

The following estimates were estimates of efficiency, cost, and lifetime obtained from industry or, in the case of hydride storage, from our best guess.

Component	Efficiency	Cost	Lifetime (years)
PV[7]	14%	$2500/kW	20
Fuel Cell[8]	47%	$2500/kW	5
Electrolyzer[9]	74%	$1900/kW	5
Hydrogen Storage (hydride)[10]	100%	$4/kWh	10
Power Conditioning[11]	92%	$1000/kW	10
Batteries[12]	90%	$200/kWh	4

ACKNOWLEDGEMENT

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